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Power System Dynamic Interaction with Turbine Generators

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16.1 Introduction

Turbine-generators for power production are critical parts of electric power systems, which provide power and energy to the user. The power system can range from a single generator and load to a complex system. A complex system may contain hundreds of power lines at various voltage levels and hundreds of transformers, turbine-generators, and loads. When the power system and its components are in the normal state, the synchronous generators produce sinusoidal voltages at synchronous frequency (60 Hz in the U.S.) and desired magnitude. The voltages cause currents to flow at synchronous frequency through the power system to the loads. The only current flowing in the generator rotor is the direct current in the generator field. Mechanical torque on the turbine-generator rotor produced by the turbine is constant and unidirectional. There is a reaction torque produced by the magnetic field in the generator, which balances the mechanical torque and maintains constant speed. The system is said to be in synchronism and there is no dynamic interaction between the power system and the turbine-generators.

At other times, the system and its components are disturbed, thereby causing a periodic exchange of energy between the components of the power system. If there is a periodic exchange of energy between a turbine-generator and the power system, we will refer to this energy exchange as power system

dynamic interaction with a turbine-generator. When this occurs the magnetic interaction in the generator together with motion of the generator rotor results in oscillating torques on the shafts of the turbine-generator. If the frequency of these torques is equal to, or near, one of the natural mechanical frequencies of the turbine-generator, excessive mechanical stress may occur along the turbine-generator rotor at critical locations. In addition, excessive voltage and current may occur in the generator and power system. Turbine-generator components known to be affected by such interaction are shafts, turbine blades, and generator retaining rings.

There have been several dramatic events resulting from power system dynamic interaction with turbine-generators, including significant turbine-generator damage. Analysis of these events has made the power engineering community aware of the potential for even more extensive turbine-generator damage from power system dynamic interaction. For these reasons, methods have been developed to identify and analyze the potential for power system dynamic interaction and countermeasures have been developed to control such interaction.

This article addresses the types of power system dynamic interaction with turbine-generators that have been identified as potentially hazardous. For each type of interaction there is a discussion of known events, physical principles, analytic methods, possible countermeasures, and references. The types of interaction to be addressed are:

- Subsynchronous resonance
- Device-dependent subsynchronous oscillations
- Supersynchronous resonance
- Device-dependent supersynchronous oscillations
- Transient shaft torque oscillations

For all of these interactions the natural frequencies and mode shapes for turbine-generator rotor systems are critical factors. As generating plants age modifications may be made that modernize or allow uprating of the units. Typical changes that can have significant effects on the rotor dynamics are replacement of shaft driven exciters with static excitation systems and replacement of turbine rotors. In a few instances electric generators or generator rotors have been replaced. All of these changes have the potential for either reducing or increasing the dynamic interaction for the specific turbine-generator. It is important that system engineers, new equipment design engineers, and service engineers all be aware of the interactions that are addressed in this article and of the potential for their occurrence at a specific plant.

16.2 Subsynchronous Resonance

Series capacitors have been used extensively since 1950 as a very effective means of increasing the power transfer capability of a power system that has long (150 miles or more) transmission lines. Series capacitors provide a capacitive reactance in series with the inherent inductive reactance of a transmission line thereby reducing the effective inductive reactance. Series capacitors significantly increase transient and steady-state stability limits, in addition to being a near perfect means of var and voltage control. One transmission project, consisting of 1000 miles of 500 kV transmission lines, estimates that the application of series capacitors reduced the project cost by 25%. Until about 1971, it was generally believed that up to 70% series compensation could be used in any transmission line with little or no concern. However, in 1971 it was learned that series capacitors can create an adverse interaction between the series compensated electrical system and the spring-mass mechanical system of the turbine-generators. This effect is called *subsynchronous resonance* (SSR) since it is the result of a resonant condition, which has a natural frequency below the fundamental frequency of the power system [1].

16.2.1 Known SSR Events

In 1970, and again in 1971, a 750 MW cross compound Mohave turbine-generator in southern Nevada experienced shaft damage. The damage occurred when the system was switched so that the generator

was radial to the Los Angeles area on a 176-mile, series compensated 500 kV transmission line. The shaft damage occurred in the slip ring area of the high-pressure turbine-generator. Metallurgical analysis showed that the shaft had experienced cyclic fatigue, leading to plasticity. Fortunately, the plant operators were able to shut the unit down before there was a shaft fracture. In each case, the turbine-generator had to be taken out of service for several months for repairs [2]. Intensive investigation in the electric power industry led to the conclusion that the Mohave events were caused by an SSR condition referred to as *torsional interaction*. Torsional interaction created sustained torsional oscillations in the second torsional mode, which has a stress concentration point in the slip ring area of the affected turbine-generator.

16.2.2 SSR Terms and Definitions

A set of terms and definitions has been developed so engineers can communicate clearly using consistent terminology. Following are definitions for the most commonly used terms. These are consistent with the terms and definitions presented in Ref. [3].

Subsynchronous: Electrical or mechanical quantities associated with frequencies below the synchronous frequency of a power system.

Supersynchronous: Electrical or mechanical quantities associated with frequencies above the synchronous frequency of a power system.

Subsynchronous resonance: The resonance between a series capacitor compensated electric system and the mechanical spring-mass system of the turbine-generator at subsynchronous frequencies.

Self-excitation: The sustainment or growth of response of a dynamic system without externally applied excitation.

Induction generator effect: The effect of having subsynchronous positive sequence currents in the armature of a synchronously rotating generator.

Torsional interaction: Self-excitation of the combined mechanical spring-mass system of a turbine-generator and a series capacitor compensated electric network when the subsynchronous rotor motion developed torque is opposite polarity and greater in magnitude than the mechanical damping torque of the rotor.

Torque amplification: The amplification of turbine-generator shaft torque at one or more of the natural frequencies of the rotor system caused by transient oscillations at subsynchronous natural frequencies of series capacitor compensated transmission systems or unfavorable timing of switching events in the electric network.

Subsynchronous oscillation: The exchange of energy between the electric network and the mechanical spring-mass system of the turbine-generator at subsynchronous frequencies.

Torsional mode frequency: A natural frequency of the mechanical spring-mass system of the turbine-generator in torsion.

Torsional damping: A measure of the decay rate of torsional oscillations.

Modal model: The mathematical spring-mass representation of the turbine-generator rotor corresponding to one of its mechanical natural torsional frequencies.

Torsional mode shape: The relative angular position or velocity at any instant of time of the individual rotor masses of a turbine-generator unit during torsional oscillation at a natural frequency.

16.2.3 SSR Physical Principles

For this discussion the simplest possible system will be considered with a single turbine-generator connected to a single series compensated transmission line as shown in Fig. 16.1. The turbine-generator has only two masses connected by a shaft acting as a torsional spring. There are damping elements between the two masses and each mass has a damping element. The electrical system of Fig. 16.1 has a single resonant frequency, f_{er} , and the mechanical spring-mass system has a single natural frequency, f_n . It must be recognized that the electrical system may be a complex grid with many series compensated

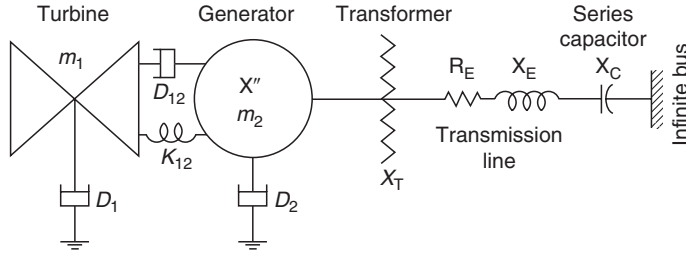


FIGURE 16.1 Turbine-generator with series compensated transmission line. (From IEEE Committee Report, Terms, definitions and symbols for Subsynchronous Resonance, *IEEE Transactions*, v. PAS-104, June 1985, © 1984 IEEE. With permission.)

lines resulting in numerous resonance frequencies f_{er1} , f_{er2} , f_{er3} , etc. Likewise, the turbine-generator may have several masses connected by shafts (springs), resulting in several natural torsional frequencies (torsional modes) f_{n1} , f_{n2} , f_{n3} , etc. Even so, the system of Fig. 16.1 is adequate to present the physical principles of SSR.

SSR is a phenomenon that results in significant energy exchange between the electric system and a turbine-generator at one of the natural frequencies of the turbine-generator below the synchronous frequency, f_o . When the electric system of Fig. 16.1 is series compensated, there will be one subsynchronous natural frequency, f_{er} . For any electric system disturbance, there will be armature current flow in the three phases of the generator at frequency f_{er} . The positive sequence component of these currents will produce a rotating magnetic field at an angular electrical speed of $2\pi f_{er}$. Currents are induced in the rotor winding due to the relative speed of the aforementioned rotating field and the speed of the rotor. The resulting rotor current will have a frequency of $f_r = f_o - f_{er}$. A subsynchronous rotor current creates induction generator effect as will be discussed further in Section 16.2.3.1. The armature magnetic field, rotating at an angular frequency of f_{er} interacts with the rotor's dc field, rotating at an angular frequency of f_o , to develop an electromagnetic torque component on the generator rotor at an angular frequency of $f_o - f_{er}$. This torque component contributes to torsional interaction, which will be discussed further in Section 16.2.3.2, and to torque amplification, which will be discussed further in Section 16.2.3.3 [3].

16.2.3.1 Induction Generator Effect

Induction generator effect involves only the electric system and the generator (does not involve turbines). For an induction machine the effective rotor resistance as seen from the armature and external power system is given by the following equations:

$$R'_r = \frac{R_r}{s} \quad (16.1)$$

$$s = \frac{f_{er} - f_o}{f_{er}} \quad (16.2)$$

where R'_r = apparent rotor resistance viewed from the armature
 R_r = rotor resistance
 s = slip
 f_{er} = frequency of the subsynchronous component of current in the armature
 f_o = synchronous frequency

Combining Eqs. (16.1) and (16.2) yields

$$R'_r = \frac{R_r f_{er}}{f_{er} - f_o} \quad (16.3)$$

Since f_{er} is subsynchronous it will always be less than f_o . Therefore, the effective generator resistance as viewed from the armature circuit will always be negative. If this equivalent resistance exceeds the sum of the positive armature resistance and system resistance at the resonant frequency f_{er} , the armature currents can be sustained or growing. This is known as induction generator effect [1,12].

16.2.3.2 Torsional Interaction

Torsional interaction involves both the electrical and the mechanical systems. Both systems have one or more natural frequency. The electrical system natural frequency is designated f_{er} and the mechanical spring-mass system natural frequency is designated f_n . Generator rotor oscillations at a natural torsional frequency, f_n , induce armature voltage components of subsynchronous frequency, $f_{en}^- = f_o - f_n$, and supersynchronous frequency, $f_{en}^+ = f_o + f_n$. When the frequency of the subsynchronous component of armature voltage, f_{en}^- , is near the electric system natural frequency, f_{er} , the resulting subsynchronous current flowing in the armature is phased to produce a rotor torque that reinforces the initial rotor torque at frequency f_n . If the resultant torque exceeds the inherent damping torque of the turbine-generator for mode n , sustained or growing oscillations can occur. This is known as torsional interaction. For a more detailed mathematical discussion of torsional interaction, see Refs. [4,5].

16.2.3.3 Torque Amplification

When there is a major disturbance in the electrical system, such as a short circuit, there are relatively large amounts of electrical energy stored in the transmission line inductance and series capacitors. When the disturbance is removed from the system, the stored energy will be released in the form of current flowing at the electrical system resonant frequency, f_{er} . If all, or a portion of the current, flows through a generator armature, the generator rotor will experience a subsynchronous torque at a frequency $f_o - f_{er}$. If the frequency of this torque corresponds to one of the torsional modes of the turbine-generator spring-mass system, the spring-mass system will be excited at that natural torsional frequency and cyclic shaft torque can grow to the endurance limit in a few cycles. This is referred to as torque amplification. For more in-depth treatments of torque amplification, see Refs. [6,7].

16.2.4 SSR Mitigation

If series capacitors are to be applied, or seriously considered, it is essential that SSR control be thoroughly investigated. The potential for SSR must be evaluated and the need for countermeasures determined. When a steam-driven turbine-generator is connected directly to a series compensated line, or a grid containing series compensated lines, a potential for SSR problems exists. There are three types of series capacitor applications for which SSR would not be expected. The first type occurs when the turbine-generator includes a hydraulic turbine. In this case, the ratio of generator mass to turbine mass is relatively high, resulting in larger modal damping and modal inertia than exists for steam turbine-generators [8]. The second type of series capacitor application that is generally free from SSR concerns has turbine-generators connected to an uncompensated transmission system which is overlaid by a series compensated transmission system. The California–Oregon transmission system is of this type with a 500 kV system that has 70% series compensation overlaying an uncompensated 230 kV transmission system. Turbine-generators are connected to the 230 kV system. Extensive study of this system has failed to identify any potential SSR problems. The third type involves series-capacitor-compensation levels below 20%. There have been no potential SSR problems identified for compensation levels below 20%.

For those series capacitor applications that are identified as having potential SSR problems, an SSR countermeasure will be required. Such countermeasures can range from a simple operating procedure to equipment costing millions of dollars. Numerous SSR countermeasures have been proposed and several have been applied [9]. Fortunately, for every series capacitor installation investigated an effective SSR countermeasure has been identified.

An orderly approach to planning and providing SSR mitigation has been proposed [1]. This includes the five steps presented below.

16.2.4.1 Screening Studies

Screening studies need to be made to determine the potential SSR problems for every turbine-generator near a series capacitor installation. These studies will probably need to be conducted using estimated data for torsional damping and modal frequencies for the turbine-generator unless the turbine-generator is in place and available for testing. Accurate modal frequencies and damping can only be obtained from tests although manufacturers will usually provide their best estimate. The most popular analytic tool for screening studies is the frequency scanning technique. This technique can provide an approximate assessment of the potential and severity for the three types of SSR: induction generator effect, torsional interaction, and torque amplification [10]. To conduct the frequency scan studies the positive sequence model for the power system is required. Generator impedance as a function of frequency is needed and may be estimated. The best estimate for turbine-generator torsional damping and modal frequencies are required. If the screening study is conducted using estimated data for the turbine-generator, data sensitivity should be examined.

16.2.4.2 Accurate Studies

If screening studies indicate any potential SSR problem, additional studies are required using the most accurate data as it becomes available from the manufacturer and from tests. The frequency scan program may be adequate for assessment of induction generator effect and torsional interaction but an eigenvalue study is desirable if large capital expenditures are being considered for self-excitation countermeasures. If the screening studies show any potential for torque amplification, detailed studies should be conducted to calculate the shaft torque levels to be expected and the probability of occurrence. The manufacturer can provide an estimated spring-mass model for the turbine-generator, which can be used for the initial torque amplification studies. The studies can be updated, as more accurate data becomes available from tests. The well-known electromagnet transient program (EMTP) is usually used for these studies.

16.2.4.3 SSR Interim Protection

If series capacitors are to be energized prior to acquiring accurate data from turbine-generator tests and the above studies indicate a potential SSR problem, interim protection must be provided. Such protection might consist of reduced levels of series compensation, operating procedures to avoid specific levels of series compensation and/or transmission line configurations, and/or relays to take the unit off-line in the event an SSR condition is detected. These precautions should also be taken when a new turbine-generator is added to an existing series compensated transmission system if studies show potential for SSR concerns.

16.2.4.4 SSR Tests

Some SSR testing will be required unless the studies discussed above show no or very low probability for the hazards of SSR. The torsional natural frequencies of the spring-mass system can probably be measured through monitoring during normal turbine-generator and system operation. To measure modal damping it is necessary to operate the turbine-generator at varying load levels while stimulating the spring-mass system. Testing will be discussed in more detail in [Section 16.2.8](#).

16.2.4.5 Countermeasure Requirements

The countermeasure selection must assure that sustained or growing oscillations do not occur and it may involve an analysis of the acceptable fatigue life expenditure (FLE) for damped oscillations. [See Section 16.2.5.3.5](#) for a discussion of FLE. Implementation of the selected countermeasures requires careful coordination. If the countermeasures involve hardware, the effectiveness of the hardware should be determined by testing. Countermeasures will be presented in more detail in [Section 16.2.6](#).

16.2.5 SSR Analysis

SSR analysis involves the identification of all system and generator operating conditions that result in SSR conditions and the determination of the severity by calculating the negative damping and shaft torque amplification. The primary computer programs used in the industry for SSR analysis are

frequency scanning, eigenvalue, and transient torque (EMTP). Some program validation has been made in the industry by comparing the results of these analytic methods with test results [11].

16.2.5.1 Frequency Scanning

The frequency scanning technique involves the determination of the driving point impedance over the frequency range of interest as viewed from the neutral of the generator being studied [10]. For frequency scanning the following modeling is required:

A positive sequence model of the power system, including series compensation, as viewed from the generator terminals.

The generator being studied is represented by its induction generator equivalent impedance as a function of slip. This can generally be obtained from the generator manufacturer. If not, an approximation is presented in Ref. [12]. Other generators in the system are generally modeled by their short circuit equivalent. Load is generally represented by the short circuit equivalent impedance viewed from the transmission system side of the transformer connecting the transmission and distribution networks.

Figure 16.2 is a typical output from a frequency-scanning program. The plots consist of the reactance and resistance as a function of frequency as viewed from the generator neutral. In addition, the 60 Hz complements of the modal frequencies have been superimposed and labeled by mode number. The use of frequency scanning to evaluate the three types of SSR will be presented below.

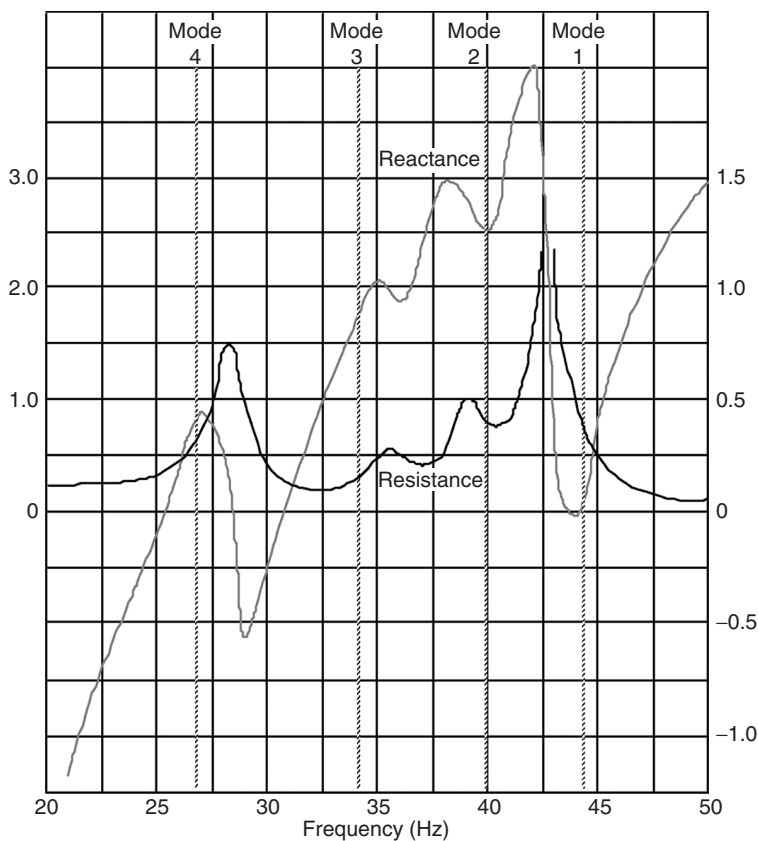


FIGURE 16.2 Frequency scan for the Navajo Project generator connected to the 500 kV system. (From Anderson, P.M. and Farmer, R.G., Subsynchronous resonance, *Series Compensation of Power Systems*, PBLSH!, San Diego, 1996. With permission.)

16.2.5.1.1 Induction Generator Effect

Frequency scanning is an excellent tool for analysis of induction generator effect. Induction generator effect is indicated when the frequency scan shows that the reactance crosses zero at frequencies corresponding to negative resistance. Such points can be identified by inspection from frequency scan plots.

16.2.5.1.2 Torsional Interaction

When a resonant frequency of the electrical system, as viewed from the generator neutral, corresponds to the 60 Hz complement of one of the turbine-generator modal frequencies, negative damping of the turbine-generator exists. If this negative damping exceeds the positive modal damping of the turbine-generator, sustained or growing shaft torque would be experienced. Such negative damping can be approximated from frequency scanning results according to Ref. [4].

Using the method of Ref. [4], the amount of negative damping for torsional mode n is directly related to the conductance, G_n , for that mode and can be calculated by the following approximate formula:

$$\Delta\sigma_n = \frac{60 - f_n}{8f_n H_n} G_n \quad (16.4)$$

where

$\Delta\sigma_n$ = negative damping for mode n in rad/s

H_n = Equivalent p.u. stored energy for a pure modal oscillation (see Ref. [10])

G_n = p.u. conductance of the electrical system including the generator on the generator MVA base at $(60 - f_n)$ Hz

$$G_n = \frac{R_n}{R_n^2 + X_n^2}$$

R_n = resistance from frequency scan at $(60 - f_n)$ Hz

X_n = reactance from frequency scan at $(60 - f_n)$ Hz

Equation 16.4 neglects the damping due to the supersynchronous components of current. This is generally negligible. Equation 6.4 in Ref. [1] includes the supersynchronous effect. Reference [10] includes a sample calculation for H_n .

The existence and severity of torsional interaction can now be determined by comparing the negative damping, $\Delta\sigma_n$, determined from frequency scanning for mode n , with the natural mechanical damping of the turbine-generator for mode n . In equation form, this is

$$\sigma_{\text{net}} = \sigma_n - \Delta\sigma_n \quad (16.5)$$

where

σ_{net} = net torsional damping for mode n

σ_n = turbine-generator damping for mode n

$\Delta\sigma_n$ = negative damping for mode n due to torsional interaction

If the net damping, σ_{net} , is negative, torsional interaction instability for mode n is indicated at the operating condition being studied. From the same frequency scan case $\Delta\sigma_n$ can be calculated for all other active modes and then compared with the natural damping, σ_m , for the corresponding mode. This provides an indication of the severity of torsional interaction for the operating condition (case) being studied. This process should be repeated for all credible operating conditions that are envisioned.

The natural torsional frequencies and modal damping for the turbine-generator will only be known accurately if the machine has been tested. If estimated data is being used the possible variations should

be accounted for. The simplest way to account for variations in modal frequency is to apply margin. One way is to calculate the maximum conductance for Eq. (16.4) within a frequency range. Reference [10] suggests a frequency range of ± 1 Hz of the predicted modal frequency. Experience has shown that estimated modal damping can significantly vary from the measured damping. Hence unless the estimated damping values are based upon measurements from other similar units, a very conservative value of damping should be used in the studies.

The frequency scanning technique, as used to calculate negative damping, has been validated through comparison with test results. There has been reasonable correlation, as shown in Refs. [10,11], when the turbine-generator model parameters are accurate. Frequency scanning is a cost effective means to study induction generator effect and torsional interaction. The results must be used with care. If the study results indicate that positive damping exists for all system conditions, but there are large reactance dips [10], tests should be conducted to validate the study results prior to making a final decision not to implement any countermeasures. Also, if frequency scanning studies indicate an SSR problem for which countermeasures are required, it is prudent to validate the studies by tests prior to committing to costly countermeasures or series compensation reduction [1].

16.2.5.1.3 Torque Amplification

Frequency scanning cannot be used to quantify the torque to be expected for a specific disturbance but it is a very good tool for determining the potential for torque amplification problems and the system configurations that need to be investigated in detail using EMTF. Reference [10] suggests that, if a frequency scan case shows a significant reactance dip within ± 3 Hz of the 60 Hz complement of a modal frequency of the turbine-generator, torque amplification might be expected. This provides an excellent screening tool for developing a list of EMTF cases to be studied. The frequency scan results in Fig. 16.2 suggest potential torque amplification for Modes 1 and 2. The largest reactance dip is near Mode 1, but is slightly detuned. The reactance dip for Mode 2 is smaller but is nearly perfectly tuned. The system configuration represented by Fig. 16.2 was studied using EMTF and found to have serious torque amplification problems, see Ref. [22].

16.2.5.2 Eigenvalue Analysis

Eigenvalue analysis for SSR is straightforward for torsional interaction and induction generator effect since they can be analyzed by linear methods [1]. The approach follows:

1. Model the power system by its positive sequence model.
2. Model the generator electrical circuits.
3. Model the turbine-generator spring-mass system with zero damping.
4. Calculate the eigenvalues of the interconnected systems.
5. The real component of eigenvalues that correspond to the subsynchronous modes of the turbine-generator spring-mass system shows the severity of torsional interaction.
6. The real component of eigenvalues that correspond to only electric system resonant frequencies shows the severity of the induction generator effects problem.

The eigenvalues to be analyzed for torsional interaction can be identified by comparing the imaginary part of each eigenvalue with the modal frequencies of the spring-mass system. The corresponding real part of the eigenvalue is a quantitative indication of the damping for that mode. If the eigenvalue has a negative real part, positive damping is indicated. If it has a positive real part, negative damping is indicated. The real part of the eigenvalue is a direct measure of the positive or negative damping for each mode. Adding the calculated damping algebraically to the inherent modal damping results in the net modal damping for the system. For a mathematical treatment of modeling for eigenvalue analysis, see Ref. [5].

16.2.5.3 Transient Analysis

Transient analysis is required to determine the potential for SSR torque amplification. The well-known EMTF is very well suited for such analysis [13]. There are various versions of the program. Bonneville

Power Administration (BPA) developed the program and has added contributions from other engineers and upgraded it through the years. A version referred to as ATP is in the public domain. Several other versions of the EMTP are commercially available. EMTP provides for detailed modeling of those elements required for assessing the severity of SSR torque amplification. This includes the power system, the generators in the system, and the mechanical model of the turbine-generator being studied.

16.2.5.3.1 EMTP Power System Model

Three-phase circuits, a neutral circuit, and a ground connection model the electrical elements of the power system. The data for the model can generally be provided in the form of phase components or symmetrical components. Special features of series capacitors can be modeled, including capacitor protection by gap flashing or nonlinear resistors. Load is usually included in a short circuit equivalent circuit at the point where it connects to the portion of the network being modeled in detail.

16.2.5.3.2 EMTP Generator Model

The electrical model for a synchronous generator being studied in EMTP is a two-axis Park's equivalent with several rotor circuits on the direct and quadrature axes. The input data can be in the form of either winding data or conventional stability data. The generator data can be obtained from the manufacturer in the form of conventional stability data. All generators in the system, other than the study generator, can generally be represented by a voltage source and impedance without affecting the study accuracy. For a detailed treatment of generator modeling for SSR analysis, see Ref. [5].

16.2.5.3.3 EMTP Turbine-Generator Mechanical Model

The turbine-generator mechanical model in EMTP consists of lumped masses, spring constants, and dampers. For torque amplification studies mechanical damping is not a critical factor. The peak shaft torque would be expected to only vary by about 10% over a range of damping from zero to maximum [1]. Hence the turbine-generator mechanical damping is generally neglected in EMTP studies.

16.2.5.3.4 Critical Factors for Torque Amplification

The most important use of EMTP for SSR analysis is to find the peak transient shaft torque that is to be expected when series capacitors are applied. It is necessary to understand that the major torque amplification events due to SSR will occur either during a power system fault or after the clearing of a power system fault. The energy stored in series capacitors during a fault will be discharged as subsynchronous frequency current that can flow in a generator armature, creating amplified subsynchronous torque. The peak shaft torque to be expected depends on many factors. Experience has shown that the dominant factors that should be varied during a torque amplification study are electric system tuning, fault location, fault clearing time, and capacitor control parameters and the largest transient torques occur when the unit is fully loaded. For a detailed discussion on system tuning and faults, see Ref. [1]. For information on capacitor controls, see Ref. [7].

16.2.5.3.5 Computing Fatigue Life Expenditure

When the torque of a turbine-generator shaft exceeds a certain minimum level (endurance limit), fatigue life is expended from the shaft during each torsion cycle. The machine manufacturer can generally furnish an estimate of FLE per cycle corresponding to shaft torque magnitude for each shaft. When plotted this is referred to as an $S-N$ curve. EMTP can then be used to predict the FLE for a specific system disturbance. One method requires the complete simulation and FLE calculation of an event over approximately 30 s, which may be costly, if numerous scenarios are to be investigated. An alternate simplified method requires some approximation. For this method EMTP studies are conducted to find the peak shaft torque that will occur for a given scenario. Since the peak shaft torques

generally occur within 0.5 s, EMTP simulation and FLE calculation time are minimized. It is assumed that after the shaft torque has peaked, it will decay at a rate corresponding to the mechanical damping of the excited modes. The FLE for the simulated event can then be calculated from knowledge of the peak torque, the decay rate, and the $S-N$ curve. This gives conservative estimates of FLE. It is important to recognize that FLE for each incident is accumulative. When the accumulated FLE reaches 100%, the shaft is expected to experience cracks at its surface but not gross failure. For more detail on computing FLE, see Ref. [1].

16.2.5.4 Data for SSR Analysis

Data requirements for SSR analysis consist of system data and turbine-generator data.

16.2.5.4.1 System Data

System data for eigenvalue and frequency scanning studies is generally of the same form as the positive sequence data used for power flow, short circuit, and power system stability studies. The data may require refinement to account for the resistance variations with frequency and for system equivalents. The classical short circuit equivalent may not be adequate when the equivalent system includes series capacitors. In such cases an RLC equivalent might be developed. It should be checked with the frequency-scanning program to determine if the equivalent reasonably approximates the driving point impedance of the system it is to represent over the frequency range of interest (10 to 50 Hz). Large load centers near the machine being analyzed may need to be represented by a special equivalent. For one outstanding case where the apparent impedance as viewed from the study generator terminal was actually measured over the frequency range of 15 to 45 Hz, it was found that the Phoenix, Arizona load must be modeled to provide a good equivalent [14]. In that case, it was found that the following load model could form an accurate equivalent:

- 60% of the total load consists of induction motor load with x_d'' of 0.135 per unit.
- 40% of the load is purely resistive.

The validity of such a model for other locations has not been determined.

For torque amplification studies using EMTP, the system data requirements are much more extensive since all three phases and ground are represented. In EMTP the series capacitors can be modeled in detail, including the capacitor protective equipment. For more detail on system data for SSR analysis, see Ref. [1].

16.2.5.4.2 Turbine-Generator Data

The IEEE SSR Working Group has developed a set of recommended SSR data items that should be furnished by the turbine-generator manufacturer. This is generally the minimum data required for SSR studies. Following is a description of the three types of data:

Generator electrical model

1. Resistance and reactance as a function of frequency for the generator as viewed from the generator terminals. This should include armature and rotor circuits.
2. Typical stability format data for the “Park’s equivalent” generator model.

Turbine-generator mechanical model

1. The inertia constant for each turbine element, generator, and exciter.
2. The spring constants for each shaft connecting turbine elements, generator, and exciter.
3. The natural torsional frequencies and mode shapes as determined for the mechanical model defined by items 1 and 2.
4. The modal damping as a function of load corresponding to the mechanical model defined by items 1 and 2.

Life expenditure curves For each shaft connecting the turbine elements, generator, and exciter a plot of the life expended per transient incident as a function of the peak oscillating torque, or an $S-N$ curve showing torque vs. number of cycles to crack initiation or crack propagation. The manufacturers should provide all assumptions made in the preparation of these curves.

For more detail on turbine-generator modeling, see Ref. [1,5].

16.2.6 SSR Countermeasures

If series capacitors are to be used and SSR analysis shows that damaging interactions may exist for one or more system configurations, countermeasures must be provided, even if the probability of an SSR event is low. Such countermeasures may not completely eliminate turbine-generator shaft FLE. Even so, prudent countermeasure selections can probably limit the FLE of any shaft to less than 100% over the expected life of the turbine-generator. A strategy for SSR countermeasure selection should be formulated during the SSR analysis stage so that it can be used as a guide for the studies to be conducted. Reference [15] presents one utility's guidelines that were developed to guide countermeasure selection, including the required SSR studies.

Numerous SSR countermeasures have been studied [16] and 12, or so, have been applied. Following is a list of the countermeasures known to have been applied with references for each. These are separated into unit-tripping and nonunit-tripping types.

16.2.6.1 Unit-Tripping SSR Countermeasures

The following countermeasures will cause the generator to be electrically separated from the power system when a hazardous condition is detected.

Torsional motion relay [17,18]: Such relays typically derive their input from rotor motion at one or two places on the turbine-generator. Rotor motion signals are typically obtained from toothed wheels mounted on the shaft. The signal is first conditioned and then analyzed for presence of modal components. The trip logic is based upon the level of signal and rate of growth. One needs to have the turbine generator stress vs. cycles to failure information to properly set the relays.

The torsional motion based relays are usually very effective in protecting against torsional interaction type of SSR problems. However, these relays may not be fast enough to protect against the worst case of torque amplification problem. The newer torsional motion based relays are microprocessor based compared to the older relays which were analog type relays.

Armature current relay [19,20]: The armature-based relays use generator current as the input signal and condition the input signal to filter out the normal 50/60 Hz component. The signal is then filtered to derive the modal component of the current. The tripping logic is based upon the level of SSR current and rate of growth. Since these relays use armature current as the input, they are capable of protecting against the torque amplification type of SSR problem.

Since the SSR current is a function of system impedance, it is usually necessary to set the relays very sensitive to be able to protect against all possible conditions. One disadvantage of setting them very sensitive is the possibility of false trips. Unfortunately, these relays are not commercially available any more.

Unit-tripping logic schemes [21]: The unit-tripping logic scheme is usually a hard-wired logic scheme, which will take the unit off-line if predetermined system conditions exist. Such schemes can be used only if there are only low probability conditions for which SSR conditions exist and one is reasonably sure that there are no other unknown system conditions for which an SSR condition can occur. Since it is difficult to assess all possible conditions for which an SSR condition may exist, this countermeasure should be applied very carefully.

16.2.6.2 Nonunit-Tripping SSR Countermeasures

The following SSR countermeasures will provide varying levels of SSR protection without electrically separating the generator from the power system. Each countermeasure is designed to offer protection for specific SSR concerns and the choice of which one to employ is based on the nature and severity of the

concern. The static blocking filter provides the broadest range of protection, but it has both the highest price and most demanding maintenance requirement.

- Static blocking filter [22,23]
- Dynamic stabilizer [24–26]
- Excitation system damper [27,28]
- Turbine-generator modifications [1]
- Pole face Amortisseur windings [9,22]
- Series capacitor bypassing [7]
- Coordinated series capacitor control with loading [9]
- Operating procedures [1]

16.2.6.3 Thyristor-Controlled Series Capacitor

The thyristor-controlled series capacitor (TCSC) is a capacitor in series with the transmission line, with a thyristor pair and small reactor in parallel with the capacitor. It can function as a series capacitor if the thyristors are blocked, as a series reactor if the thyristors fully conduct, or as a variable impedance when the duty cycle of the thyristors is varied. The device has been applied to improve stability in weak AC networks and to protect the series capacitor from transient overvoltage. It is expected that TCSCs will be used to control SSR interactions in the future.

Two installations in the United States have demonstrated control algorithms for SSR concerns [29,30]. These projects were in locations where there was a low probability of sustained or growing oscillations, but they provided both demonstrations of control algorithms and equipment installation and operation. They also provide information about required ratings for the components of the TCSC and reliability of the power electronic components, the cooling systems, and the control systems.

There have been a large number of technical studies and papers describing control algorithms, equipment sizes, and the most effective location in the network for TCSC installations. A sample of this information is contained in Refs. [31–33]. These circuits are considered to be the most effective means to directly control SSR in the transmission network. As network loading increases and the need to have high levels of series compensation increases, there will be greater justification for this equipment.

16.2.7 Fatigue Damage and Monitoring

Fatigue damage of turbine-generator shafts is certainly undesirable, but it may not be practical to completely avoid it. Therefore, it is important to understand the consequences of fatigue damage, and to know how to quantify any fatigue damage experienced so that gross shaft failure is avoided [3,18].

The consequences of high cycle fatigue and low cycle fatigue differ. In the case of high cycle fatigue, where purely elastic deformation occurs, there is no permanent deformation and no irreparable damage. High cycle fatigue is characterized by millions of stress cycles, consequently it rarely occurs in the main shaft sections of a turbine-generator. It is said that 100% FLE occurs when cracks are initiated at the stress concentration points on the shaft surfaces. When this point is reached, cracks will be propagated as additional torsional stresses above the endurance limit (at the stress concentration point at the end of the crack) are experienced. This does not mean that shaft failure will occur when 100% FLE is reached. On the contrary, the ultimate strength of the shaft in torsion is not significantly reduced. It does mean that cracks will be expected to increase in number and size if appropriate action is not taken. Fortunately, machining the shaft surface to remove the cracks can effectively restore the total shaft integrity. Cracks can be identified by visual inspection at stress concentration points on the shaft. Even so, it may be very costly to shut a unit down for a visual inspection following an incident suspected to result in significant FLE. For this reason, torsional monitoring techniques have been developed to provide a permanent history of torque experienced by each turbine-generator shaft. The most likely phenomenon leading to

high cycle fatigue is sustained torsional interaction where the torsional amplitude is limited by nonlinear damping.

In the case of low cycle fatigue, characterized by a small number of very large amplitude stress cycles for which plastic deformation occurs, the consequences may be quite different from those in high cycle fatigue. When plastic deformation occurs, there is irreversible shaft deformation in torsion (kink). In the most severe cases this can result in a bending moment being applied to the shaft each revolution. If the unit continues to operate in this condition, shaft failure in the bending mode may occur. If a monitor detects low cycle fatigue and there is a corresponding increase in lateral vibration, the shaft should be inspected. Whether there should be an immediate unit shutdown for such an incident is subject to judgment. The most likely phenomenon leading to low cycle fatigue is torque amplification.

Shaft torque monitoring techniques have been developed which will provide a permanent history of the approximate torque experienced by each turbine-generator shaft. This information is extremely useful in making a decision following a unit trip by SSR relay action or an unusual event such as out-of-phase synchronization. The options are:

1. Take the unit off-line and inspect the shaft.
2. Inspect the shaft at the next scheduled outage.
3. Synchronize, load the unit, and continue to operate without interruption.

A wrong decision could cause significant shaft damage or an unnecessary unit outage. Several methods have been developed for monitoring shaft torque as reported in the literature [18,34–38].

16.2.8 SSR Testing

The analytic methods and corresponding software for SSR analysis can be very detailed, but they have limited value unless the required data for the electric system, generators, and turbine-generator spring-mass-damping system is available and is reasonably accurate. It has been found from tests that the torsional frequencies are usually within 1 Hz of that predicted by the manufacturer. This implies that the spring-mass model data is reasonably accurate. The turbine-generator manufacturers estimate torsional damping, but testing has shown that damping predictions, when compared with site tests, may have large variations. Therefore, little confidence can be placed in predicted damping unless it is based upon measured data from similar units. Accurate torsional damping values can only be obtained from tests.

SSR tests can vary in their complexity, depending on their purpose, availability of turbine-generator rotor motion monitoring points, type of generator excitation system, power system configuration, and other factors. The minimum and simplest tests are those used to identify the natural torsional frequencies of a turbine-generator. Tests to measure torsional damping are more difficult, particularly at high loading. Various types of tests may be devised to test the effectiveness of countermeasures.

16.2.8.1 Torsional Mode Frequency Tests

The objective of these tests is to perform a spectrum analysis of rotor motion or shaft strain in torsion at points that respond to all active modes of interest. Rotor motion signals can be obtained by demodulating the output of a proximity probe mounted adjacent to a toothed wheel on the rotor. Shaft strain is obtainable from strain gauges fixed to the shaft [39]. With the use of digital spectrum analyzers, natural torsional frequencies can be measured by merely recording the appropriate signals during normal operation of the turbine-generator unit without any special switching [1].

16.2.8.2 Modal Damping Tests

The most successful methods for measuring damping is to excite the spring-mass system by some means and then measure the natural decay rate following removal of the stimulus. Two methods have been used to excite the torsional modes. These methods are referred to as the “impact method” and the “steady-state method.”

The impact method requires the application of an electrical torque transient to the turbine-generator being tested. The transient must be large enough to allow the decay rate of each modal response to be

measured during ring down. Rotor motion is generally the preferred signal, but shaft stress has also been used successfully. Since the transient excites all modes, a series of narrow-band and band-reject filters are applied to the signal to separate the response into the modal components of interest. Switching series capacitor banks or line switching can create the required transient. Synchronizing the generator to the power system may also provide adequate stimulus. Such tests are described in Refs. [39,40].

The steady-state method uses a sinusoidal input signal to the voltage regulator of the excitation system, which produces a sinusoidal component of generator field voltage. Some types of excitation systems can create a large enough sinusoidal response of the generator rotor to provide meaningful analysis. The frequency of the signal is varied to obtain a pure modal response of rotor motion or shaft strain. When a steady-state condition with pure mode stimulus has been obtained the stimulus is removed and the decaying modal oscillation is recorded and plotted. The decay rate is a measure of the modal damping. This process is repeated for each torsional mode of interest. The steady-state method is the preferred method since pure modes can be excited. This method is only applicable to generators whose excitation system has sufficient gain and speed of response to produce a significant torque from the voltage regulator input signal. Such tests are reported in detail in Refs. [39,40].

The damping measured from either of the two test methods is the net damping of the coupled mechanical and electrical systems. Depending on the system configuration during the damping tests, the measured damping may include positive or negative damping due to interaction of the mechanical and electrical systems. This effect can be calculated from eigenvalue studies or from frequency scanning studies in conjunction with the interaction Eq. (16.4). To obtain the true mechanical damping, the measured damping must be corrected to account for the interaction in accordance with the following equation:

$$\sigma_n = \sigma_{\text{meas}} \pm \Delta\sigma_n \quad (16.6)$$

where

σ_n = mechanical modal damping for mode n

σ_{meas} = measured damping from tests

$\Delta\sigma_n$ = positive or negative damping due to interaction

It is usually important to have measured torsional damping of all active subsynchronous modes as a function of load, ranging from no load to full load. It is often more difficult to obtain full load damping because modal response decreases as damping increases and damping generally increases with load. It may be impossible to obtain adequate torsional excitation at full load. See Fig. 16.3 for results of such tests reported in Ref. [39]. Fortunately, it is the damping values at low loads that are of most interest because they represent the most severe interactions.

16.2.8.3 Countermeasure Tests

Testing the effectiveness of any countermeasure to be applied is important, but may not be feasible. For example, if a countermeasure is to limit loss of shaft life for the most severe transient, it is not reasonable to conduct such a test. Tests for effectiveness of torsional interaction countermeasures are practical and should be made whenever possible. One method is to conduct damping tests, as described in Section 16.2.8.2, with the countermeasure in service and the system configured to yield significant negative damping due to torsional interaction. Such tests are described in Refs. [23,41].

If SSR relays are to be applied, it may be possible to initiate a unit trip by SSR relay action under controlled conditions to verify proper operation. This has been accomplished, at least at one plant, by reducing the relay settings to a very sensitive level, and then causing rotor oscillations by the steady-state method described above. The stimulus can be increased to a level of sustained modal oscillations that will cause the relay to pick up. For the reduced setting, the shaft torques are kept below the endurance limit. Such a test provides confidence in both the relay capabilities to initiate a unit trip and the correct wiring of the circuits from the relay output to the circuit breaker trip coils.

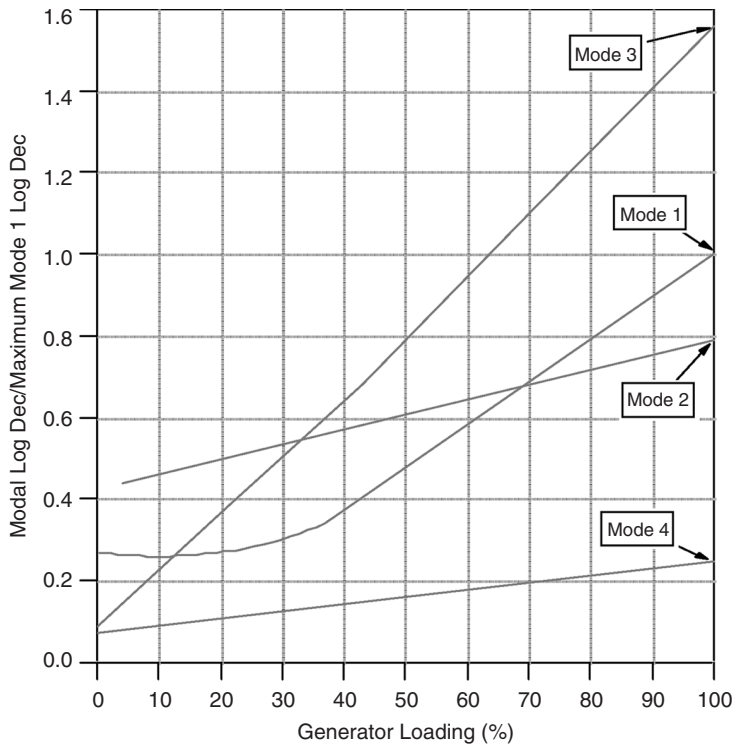


FIGURE 16.3 Variations of modal damping as a function of generator load for Navajo Generators. (From Anderson, P.M. and Farmer, R.G., *Subsynchronous resonance, Series Compensation of Power Systems*, PBLSH!, San Diego, 1996. With permission.)

16.2.9 Summary

Consideration must be given to the potential for SSR whenever series capacitors are to be applied. Even so, the ability to analyze and control SSR for the extreme problems encountered has been clearly demonstrated over the last 30 years. Various countermeasures for SSR control have been developed and successfully applied. In many cases, the sole SSR protection can be provided by relays. Monitoring has a place in the SSR field to provide a permanent history of the torques experienced by the shafts and the accumulative shaft life expenditure. Such information can be used to schedule shaft inspection and maintenance, as required, to maintain shaft integrity. Continuous monitoring of SSR countermeasure performance by modern digital equipment can also be cost effective.

If potential SSR problems are identified when series capacitor applications are considered, there is a clear course established by the utility industry. Analytical methods are available for either cursory or detailed analysis. Countermeasure selection guidelines used by others are available. Testing methods have been developed that vary from simple monitoring to sophisticated signal processing and system switching. SSR can be controlled, thus making it possible to benefit from the distinct advantages of series capacitors.

16.3 Device-Dependent Subsynchronous Oscillations

Device-dependent subsynchronous oscillations have been defined as interaction between turbine-generator torsional systems and power system components. Such interaction with turbine-generators has been observed with DC converter controls, variable speed motor controllers, and power system stabilizers (PSS). There is potential for such interaction for any wide bandwidth power controller located near a turbine-generator.

16.3.1 HVDC Converter Controls

In 1977, tests were conducted to determine the interaction of the Square Butte HVDC converter in North Dakota with the Milton Young #2 turbine-generator. It was found that both the high-gain power modulation control and the HVDC firing angle control destabilized the first torsional mode of the turbine-generator at 11.5 Hz. Fortunately it was also found that the basic HVDC controls created growing torsional oscillations of the turbine-generator in the first torsional mode for a specific system configuration that nearly isolated the turbine-generator and HVDC converter from the rest of the AC network. Careful analysis of this phenomenon shows that any HVDC converter has the potential for creating subsynchronous torsional oscillations in turbine-generators that are connected to the same bus as the HVDC converter. The potential reduces as the impedance between the two increases or as additional AC circuits are connected. The HVDC system appears as a load to the turbine-generator. The load would be positively damped for crude firing angle control. Successful converter operation requires sophisticated firing angle control. This sophisticated control may make the converter appear as a negatively damped load in the range of 2–20 Hz. The potential problem of HVDC converter control interaction with turbine-generators can be investigated by eigenvalue analysis. If negative damping is expected the problem may be solved by retuning converter controls. Also a subsynchronous damping controller has been conceptually designed as reported in Ref. [42]. Reference [43] describes a field test and analysis of interaction between a turbine-generator and a HVDC system.

16.3.2 Variable Speed Motor Controllers

In 1979 and 1980, a European fossil fired power plant experienced subsynchronous oscillations of a 775 MW, 3000 RPM turbine-generator. The plant was equipped with variable speed drives for the boiler feedwater pumps. The pump drives are equipped with six-pulse subsynchronous converter cascades. For such a converter, the load power to the motors has a component at six times the motor slip frequency. At specific load levels the feedwater pump speed is such that the load has a component whose frequency corresponds to the 50 Hz complement of one of the natural torsional frequencies of the turbine-generator. Under these conditions, the pump load acts as a continuous torsional stimulus of the turbine-generator. FLE could occur under such conditions, depending on the magnitude of the torsional oscillations. A torsional stress monitor detected the event discussed above. Modeling and analysis in EMTP or similar programs could probably predict such an event but there is no record of such an analysis. The countermeasure applied to the above problem controls feedwater pump speed to avoid speeds that would excite the natural torsional modes of the turbine-generator [44].

16.3.3 Power System Stabilizers

In 1969, a 500 MW unit was commissioned at the Lambton Generating Station. A PSS was added some time later to provide positive damping for the local mode of about 1.67 Hz. The PSS derived its input signal from rotor motion at a point adjacent to the generator mass. When the PSS was initially tested sustained 16.0 Hz torsional oscillations of the generator were observed. 16.0 Hz corresponds to the first torsional mode of the turbine-generator mechanical system [45]. From analysis and simulation it was determined that if the torsional oscillations were allowed to continue, severe turbine-generator shaft damage would occur. It was also learned that any small generator rotor motion at the first torsional mode (16.0 Hz) creates a 16.0 Hz signal input to the PSS. The gain and phase of the PSS and the excitation system created an oscillating torque on the generator at 16.0 Hz, which reinforced the initiating 16.0 Hz oscillation. This type of problem can be analyzed using either eigenvalue or EMTP-type computer programs, which have provisions for modeling the turbine-generator mechanical system. The essence of the problem can be analyzed manually or using any software, which will provide the data for Bode plots.

There are various countermeasures that can be applied to deal with the PSS problem. The countermeasures used at Lambton consisted of moving the rotor motion sensing location to a point of the

spring-mass system, which has no torsional motion, or provides positive damping, at the active torsional modes. In addition, a 16.35 Hz notch filter was included in the PSS to drastically reduce the gain for the first torsional mode. Others use a high order low pass filter or a wide-band band-reject filter in the PSS loop to insure that torsional oscillations are not generated by the PSS.

16.3.4 Other

In general, any device that controls or responds rapidly to power or speed variations in the subsynchronous frequency range is a potential source for excitation of subsynchronous oscillations. The technical literature includes the effect of governor characteristics on turbine-generator shaft torsionals [46] and subsynchronous torsional interactions with static var compensators (SVCs) [47].

16.4 Supersynchronous Resonance

The term supersynchronous resonance (SPSR) is used here to refer to a torsional resonant condition of a turbine-generator mechanical system at a frequency greater than the frequency corresponding to rated turbine speed and power system rated frequency. Such a resonant condition can be excited from the power system. There have been at least three incidents of turbine blade failure contributed to the excitation of turbine-generator torsional modes that are very near to twice the AC operating frequency (120 Hz for 60 Hz AC systems).

The excitation for these events is the double frequency torque that results from unbalanced phase currents in the AC system. In per unit the magnitude of this torque is very nearly equal to the magnitude of the negative sequence AC current. This value is dependent on transmission line design and balance in system loads. For most systems it is less than 2% of rated torque, but it may increase for some contingencies. The excitation frequency will also vary due to variations in synchronous frequency. This variation is most pronounced in very weak systems and in isolated systems.

16.4.1 Known SPSR Events

In 1985, a turbine-generator outside the United States experienced the failure of eight blades in the last stage of a 1800-RPM low-pressure turbine with 43-in. last-stage blades. The blades failed at the root attachments to the rotor disk due to high cycle fatigue. A one-year outage was required to repair the unit. In 1993, a turbine-generator in the United States experienced the failure of two blades in the next to last row of a 1800-RPM low-pressure turbine with 38-in. last-stage blades. The blades failed at the dovetails on the rotor disk. A 49-day outage was required to repair the unit. The turbine-generator units for both incidents were from the same manufacturer and both have relatively long turbine blades on 1800-RPM low-pressure turbines. Similar events occurred in the 1970s to a 1800-RPM turbine-generator from a different manufacturer [48].

16.4.2 SPSR Physical Principles

Long turbine blades, such as the 38- and 43-in. blades on 1800-RPM low-pressure turbines, often have a natural vibration frequency near 120 Hz when coupled to the rotor disk. A blade-disk with a natural frequency near 120 Hz may be excited by torsional oscillations near 120 Hz [49]. Although individual turbines are designed to avoid 120 Hz natural torsional frequencies (torsional modes) with at least 0.5 Hz margin, the complex modes of coupled shaft systems at these frequencies are difficult to calculate with sufficient accuracy. The following scenario can contribute to turbine blade failure due to high cycle fatigue.

Negative sequence current flows in the generator armature due to unbalanced loads, untransposed lines, or unbalanced faults. The resulting magnetic flux interacting with the field flux results in a double AC system frequency electromagnetic torque applied to the generator rotor. This will excite torsional oscillations if there is a torsional mode of the shaft system at this frequency with sufficient net torque along the generator rotor. Torsional oscillations, at points along the shaft where long turbine blades are

attached, can excite blade vibration if the blade-disk natural frequency is approximately the same as the rotor mode frequency (120 Hz for 60 Hz systems) and the coupled mode can be excited by torque applied to the generator rotor. Continuous blade vibration, or numerous transient events, will initiate cracks at the stress concentration points and finally blades will fail.

For the above scenario, generally there is a torsional mode within 0.5 Hz of 120 Hz. Turbine-generator designers have made efforts to avoid torsional frequencies near 120 Hz but have not always had the technology to accurately calculate the frequencies for the higher torsional modes near 120 Hz. The 1993 blade failure has been contributed to an undetected torsional mode within 0.5 Hz of 120 Hz. For the 1985 blade failure, there were no natural modes within 0.5 Hz of 120 Hz but the turbine-generator was operating in a relatively small power system whose frequency varied significantly. These frequency variations, in conjunction with negative sequence generator current, excited the torsional modes that were 1–2 Hz away from 120 Hz.

Tests and experience have shown that generators experience continuous negative sequence current ranging from 1 to 3%. Of course, much higher negative sequence currents occur during unbalanced fault conditions. Therefore, if the blade-disk natural frequencies are near 120 Hz, it is essential that there are no natural torsional frequencies between 119.5 and 120.5 Hz that can be excited by torque applied to the generator rotor. The turbine-generator manufacturer calculates the blade-disk natural frequencies and the torsional natural frequencies. Unfortunately, the calculated frequencies may not be sufficiently accurate to determine if blade failure is to be expected. The turbine-generator natural frequencies can be accurately determined from tests. An off-line test has been devised which will accurately show the natural torsional frequencies at no load. This is called a ramp test and consists of monitoring torsional strain at critical points while negative-sequence current flows in the generator armature circuit and the turbine-generator speed is accelerated. The negative sequence current is induced by shorting two generator terminals and controlling field voltage with a separate power supply. The ramp test and other tests are described in Refs. [48,50]. Using accurate test data, an analytic model can be developed by an iterative process. The resulting analytic model can be used to find appropriate countermeasures.

16.4.3 SPSR Countermeasures

The countermeasures that have been applied to avoid turbine blade failure, caused by SPSR, involve either moving natural torsional frequencies away from 120 Hz or changing the mode shapes, of modes near 120 Hz, so that they are not excited by electrical torque applied to the generator rotor. This has been successfully accomplished by several methods. One is to braze the tie wires on all last-stage blades. This modification may increase torsional frequencies and it alters the participation of individual blades in the oscillation. A second countermeasure involves adding a mass ring at an appropriate location along the torsional spring-mass system. This modification may reduce the critical torsional frequencies and it will change the mode shapes. Other methods include machining critical sections along the shaft system and changing the generator pole face slotting to move frequencies and modify mode shapes. Tests to determine the natural torsional frequencies following modifications should be made to verify the analytic model [48,50]. A relay has been proposed to alarm or trip the turbine-generator for combinations of negative sequence current and off-nominal frequency operation deemed to be excessive.

16.5 Device-Dependent Supersynchronous Oscillations

There has been a series of events that resulted in turbine-generator damage due to SPSR stimulated by a power system device. This type of interaction is referred to as device-dependent supersynchronous oscillations (DDSPSO).

16.5.1 Known DDSPSO Events

The Comanche Unit 2 near Pueblo, Colorado went into service in 1975 and during the period of 1987 to 1994, the unit suffered generator damage. In 1987, there was a crack in the generator shaft. In 1993, there

were two failures of the rotating exciter. In 1994, there was a retaining ring failure resulting in serious rotor and stator damage [51]. All have been contributed to the same phenomena.

16.5.2 DDSPSO Physical Principles

Comanche Unit 2 is about 3 miles from 2–60 MVA steel mill arc furnaces. The arc furnaces have an SVC for flicker control. It has been found that the SVC had a control loop instability that caused negative sequence current to flow in the armature of Comanche 2 at a frequency near 55 Hz. The instability resulted in a 5 Hz amplitude modulation of the 60 Hz SVC current. This modulation created upper and lower sidebands of 55 and 65 Hz in all three phases, but in reverse rotation. The 65 Hz component did not appear outside the SVC delta winding but a 55 Hz negative sequence component flowed in the generator armature. The frequency of this component varied between 54 and 58 Hz, depending on the steel mill operating conditions. This produced a component of electromagnetic torque in the frequency range of 114 to 118 Hz. The natural torsional frequency for Mode 6 of Comanche 2 was about 118 Hz prior to the retaining ring failure. The mode shape for Mode 6 shows large displacement at the two ends of the generator. Therefore, stimulus from the SVC created torsional oscillations was sufficiently large and sustained to result in high cycle fatigue of the generator shaft, rotating exciter, and retaining ring before the root cause of the problem was found.

16.5.3 DDSPSO Countermeasure

Extensive testing was performed to determine natural modal frequencies for the turbine-generator, the components of armature current, and the arc furnace and SVC stimulus. Once the root cause of the problem was determined, it was a simple matter to retune the control circuit of the SVC [51].

16.6 Transient Shaft Torque Oscillations

Turbine-generator design has been guided for many years by a simple requirement for the strength of the shaft system. This requirement in the American National Standards Institute (IEEE/ANSI) Standard C50.13 states “A generator shall be designed so that it can be fit for service after experiencing a sudden short circuit of any kind at its terminals while operating at rated load and 1.05 per unit rated voltage, provided that the fault is limited by the following conditions:

- The maximum phase current does not exceed that obtained from a three-phase sudden short circuit
- The stator winding short time thermal requirements are not exceeded.” [52]

Although this requirement does not refer to the turbine-generator shaft, this transient has been used for many years to verify the shaft design. It has generally been assumed that the more frequent shocks resulting from more remote short circuits, out-of-phase synchronizing, and transmission line switching would have low enough magnitudes and be infrequent enough that fatigue issues did not have to be considered. Experience has verified this assumption. While there have been reports of damage to coupling faces and coupling bolts, there have not been many reports of more severe damage.

When shaft damage due to dynamic interactions between turbine-generators and transmission systems became a concern, more detailed analysis of the effects of short circuit and line switching transients was performed [53]. This analysis generally confirmed that system disturbances did not result in larger shaft torques than terminal short circuits unless these disturbances involved dynamic interactions, series capacitors, or multiple switching events. The most common scenario for multiple switching events is fault clearing in the transmission system. When a fault occurs in the network, turbine-generators experience a step change in torque. The fault clearing 50–150 ms later produces a second step change usually in the opposite direction. This second shock can reinforce oscillations initiated by the fault if the timing coincides with critical timing for one of the shaft natural frequencies.

Unsuccessful high-speed reclosing events coupled with low damping for shaft oscillations would provide more opportunities for further amplification. For this reason turbine-generator manufacturers requested that the practice of high-speed reclosing be discontinued for multiphase faults on transmission lines connected to generating stations.

Very recently damage has been reported at one of the older operating nuclear stations in the United States [54]. Both turbine-generators at this station had to be removed from service when changes in shaft vibration became unacceptable. Relatively long cracks were discovered emanating from coupling keyways in the generator shaft. The analysis determined that these cracks were caused by multiple torsional events during the lifetime of the machines. There is no detailed history of the specific transients, but repairs including a redesign of the coupling and keyways make the units less susceptible to further damage. This experience has renewed industry interest in transient shaft torque oscillations and suggests that further analysis and monitoring are warranted.

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